N.kr. 18,00

DECEMBER 1981

noroil 12

ISSN 0332-544X

Financing offshore exploration and development in the 1980s

— and insuring the investments

North Sea Gas

As Norway sees its gas reserves boost, challenges emerge from development problems and shrinking markets.

NORWAY is about to become a gas nation rather than an oil nation if judged from the country's developing resource base. This development could well prove unfortunate, particularly because the market may not be readily available for large new quantities of expensive natural gas from Norway. (See story on page 26.)

As exploration and appraisal drilling proceeds north of 60°N in the North Sea it becomes increasingly well documented that extremely effective sealings on top of Jurassic main structural elements have helped to preserve large quantities of gas. It is widely believed now that close to 2,000 billion m^3 of gas is recoverable from licenced blocks north and south of 62°N and from 31/3, 31/5 and 31/6.

A common feature about these gas accumulations however, is the obvious obstacles to developing them. Some of the reservoirs are extremely complicated to produce, which is the case for Sleipner, while other are in deep water (the 31st quadrant) and still others contain gas in association with oil, which makes them vulnerable to strict depletion measures. For those gas fields recently located off the coast of north Norway the distance to available markets presents additional problems.

The ratio between oil and gas in Norway's proven reserves base is now about 50/50 with gas building up its share. I could then be desirable for Norway to produce at the same ratio, something that would mean stepping up gas production to approximately 50 billion m^3/yr from the present level of 25-30 billion standard m^3/yr. The crucial question will then be whether the market can take it.

The next large scale natural gas development project to be put before the Norwegian government for approval is the Sleipner complex. Extensive appraisal drilling has been going on in the Sleipner area during the last year and a half and estimates of recoverable reserves now stand at 200 billion m^3 plus; ie the order of magnitude of the Frigg field. A declaration of commerciality and a project development plan are expected for next year.

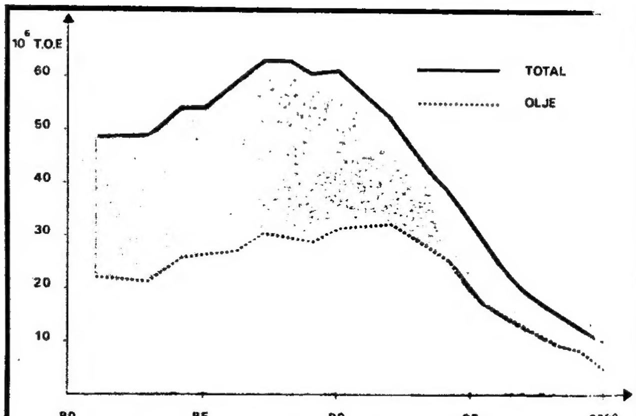
But operators in the area are faced with at least two major constraints when trying to wrap a Sleipner developments package together. Firstly, there is the complexity of the reservoirs; the complex consists of six different structures spread over a relatively wide area. All structures produce CO_2 with the gas, a fact that could make development a painful exercise. Secondly, marketing of Sleipner gas will have to be executed in the very near future, in the wake of the Russian/German gas deal (details on page 26) and in a market that is not exactly wide open for additional expensive gas in the part of the 80s and the 90s.

Recent appraisal of the Sleipner Gamma structure confirmed that this structure differs from the other structures in the complex in as much as the main producing zones have sweet gas, while CO_2 contents were encountered further down. The most westerly structure in the complex straddles the border line to the UK sector of the North Sea.

The structural configuration of the Sleipner complex opens the possibility of step-by-step development. How much of the Sleipner gas will end up in a UK transportation system, in the Statfjord/Ekofisk system or in its own separate pipeline is impossible to predict. A separate pipeline from Sleipner would have to carry 10 — 15 billion m^3 of gas annually.

Even more serious problems are encountered in the possible development of the 700 sq km «Flathead» structure in Norway's quadrant 31. Waterdepths are around 1,100ft and the gas is overlaying a thin layer of oil that could be tricky to produce if required. With recoverable oil reserves in the reservoir estimated more than two billion barrels there is no way it can left in the ground (see *Noroil* September 1981, p 37). Gas production from this giant field could, therefore, be postponed until the 1990s or later.

Blocks 30/7 and 30/4 have a recoverable reserve potential of at least 70 billion m^3 while 30/6 could prove a giant both in oil and gas. It is of the most promising gas prospects in Norwegian waters, and has been ved to the best such prospect in Norway's fourth round of allocations. The structure has, however, not been drilled yet, a fact that has been rather annoying



Production from fields developed and committed for development off Norway.

those responsible for resource management planning in Norway.

Finally in the North Sea, block 15/3, now under appraisal, could contain more than 50 billion m³ of recoverable gas.

Perhaps the biggest dilemma for the Norwegian government will be how to dispose of the dominant gas reserves in a limited gas market. Marketing gas from what are basically gas fields could prove difficult enough, and could have a damaging effect on the possibility of finding a market later on for associated gas should further oil field development projects be implemented in the late '80 or early '90s. Something will have to be put on stream by that time to keep production and revenue at the required levels.

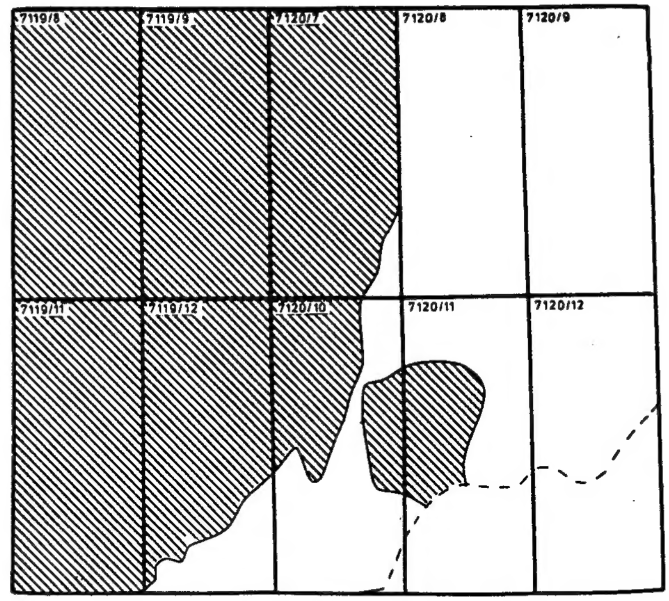
Moreover developments in the North Sea will eventually have to be balanced against the prospects of producing gas from fields recently discovered further north on Norway's continental shelf.

Off Troms Statoil, earlier this year, tested more than two billion m³/day from three producing zones in well 7120/8-1. Initial estimates of recoverable reserves from the structure vary from 100 to 200 billion m³ dependent on the homogeneity of the structure which has a fault in its approximate centre. Norsk Hydro tested 723,000 m³/day in well 7120/12-1 in the same area.

Voices are already heard in support of a rapid appraisal of the gas potential off Troms and of planning for early production. Appraisal drilling may well be speeded up from next year.

Plans are emerging for a possible large dia pipeline overland from Troms via Sweden to the European continent. If this is one option for the 1990s one will have to consider very thoroughly the potential markets for large quantities of gas in such a pipeline. In any case such gas will have to complete with available gas from other sources, even with gas from Norway's own North Sea sector.

Such consideration might well be the nucleus of Norway's emerging natural gas dilemma. ■



Upper Jurassic hydrocarbons accumulation in the eastern portion of the Troms I area.

Argyll Field
gets flexible flowlines

HAMILTON Brothers has placed an order with Coflexip of France for flexible pipeline to replace the two Argyll field flowlines which sank in September while on tow to the field. Hamilton Brothers confirm that the flowlines, which are still on the seabed will be raised or buried in spring of next year "when it becomes practicable to do so".

The lines were fabricated by Kestrel Marine and were being transported to the Argyll field by Smit International using the mid-depth tow method. This had previously been used successfully by Occidental on North Claymore and is to be used by Shell for the central Cormorant UMC.

After the failure of the tows it seemed as if litigation might result and the question of liability remains to be settled. Hamilton appears now to have washed its hand completely of the matter, saying it never took delivery of the lines, and Kestrel Marine is reported in dispute with the supplier of the steel sections over the specification of the lugs attached to the flowlines. ■

Danish Offshore
mopping up marginals

TEXACO's interest in the untouched tiny marginal gas fields offshore Denmark is obvious. The company is a member of the Danish Underground Consortium (DUC) which is tapping Tyra/Roar/Gorm/Dan gas for trunklining to Jutland through 30-inch diameter pipe, 225 kilometre long. (Lines laid 1982, on stream 1983).

Trunkline capacity quadruples gas currently earmarked for tapping, so Texaco eyes engineering chances for temporary, cheap and mobile production platforms on fields which consultants De Golyer and MacNaughton have identified in the Danish sector.

US designers will float plans before Christmas in Copenhagen for restructured jackups to be installed offshore for five years of field life, a short time compared to the 13/20 year cycle expected for North Sea giants. ■

German Offshore
H-15 is questioned

FOR West Germany's H-15 block, engineering designer Deutsche Babcock is locked into project discussions with entrepeneur Norwest-Deutsche Kraftwerke over the true commercial prospects for reserves which have lead to plans for offshore power generation cabled to shore.

Seismic this year has prompted additional drilling in 1982 to supplement information from testflows of one million cubic metres per day drilled in November 1980.

Much forward planning has been put into installation of gas/steam turbines atop a squat jackup structure. ■

Storgas - W. Germ - $4.70
Statfjord - - $ 5.50
Algeria - { 5.00 old
{ 5.50 - 6.11 new

Giant gas gets going

The price agreed for Russian gas to West Germany in the big Yamburg pipeline project is certain to have quite decisive impact on price levels for additional gas supplies to Western Europe and could abruptly bring down the hopes of suppliers like the Algerians and the Norwegians of obtaining the crude oil price parity levels they have been claiming.

AT a price of around $4.70 million btu at the German border — 1981 base price — and escalation linked mainly to fuel oil prices, the Russian gas is approximately $1.10 below that obtained by the Norwegians for Statfjord gas one year ago. July 1980 base price for Statfjord gas was $5.50 and present level around $5.80 million btu.

The price for the Russian gas is claimed by the German utilities to be «much more realistic than that paid for Statfjord gas, and the Statfjord deal was an exception which will not be repeated.» Speculation is that political pressure helped Statfjord gas price.

The cost to the Ruhrgas-led German consortium is claimed to reflect the realistic market value in the European continent, and it must be a severe blow to Algeria's Sonatrach which is stalemated in its talks with the French and the Italians. There are signs that at least the Italians will now avoid any price agreement with Sonatrach for TransMediterranean gas until they have settled the price for Italy's share of the Yamburg gas. Assuming that price will be in line with what the Germans have obtained, Sonatrach's position will be rather tricky.

Officially a settlement was reached on the price formula for Algerian gas to France during the official visit of French President Francois Mitterand to Alergia earlier this month. Details of the basics of the formula have not been disclosed, but there was limited sign of headway having been made by the two arbitrators appointed by the two governments: M'hamed Yala for Algeria and Jean-Marcel Jeanneney for France.

Not only have the two countries to establish the price to be paid for the third contract of five billion cubic metres a year which is to be landed at Montoir-Debretagne, but there is also the demand of a price adjustment for existing deliveries via Fos. At the moment France is paying $4.27 per million btu FOB which means about $5.00 CIF at Fos. In view of the higher cost of the Montoir terminal, the CIF price at Montoir would probably be another 60 cents.

Because of the price level at which the French are expected to buy the Soviet gas — slightly more than the $4.70 agreed for German gas at the border — and the recent refusal of Italy to pay Algeria $5.50 FOB there seems little or no chance of the Algerians getting whatever is today's value of the $6.11 per million btu they asked two years ago.

The general view in the industry seems to be a slight surprise that the price for Russian gas to West Germany came as low as $4.40. The short term effects on the European gas market and its price levels could be rather worrying for those who intend to supply additional gas to this market in the 1980s, and even in the early 90s. On the longer term, however, a «realistic» price for the 40 billion cubic metres supplied through the Yamburg pipeline could have a healthy effect on the development of the European gas market and thus establish a consumption that would open for more available gas to get to this market in the late 1990s, ie from Norway, Africa and the Middle East.

As it stands today, however, the Ruhrgas/Sojuzgazexport contract is a serious blow to the idea of high crude oil parity gas pricing. In the meantime Norway's Minister of Petroleum and Energy, Vidkunn Hveding, revealed the new Norwegian government's attitude to gas pricing at the recent seminar organised here by OPEC. «My government believes that gas prices should reflect the place of gas in the combined energy market of today and be subjected to escalation in accordance with our expectations of its place in the future,» said Hveding. He made no reference to the principle of crude oil parity pricing, so strongly pursued by the previous Oslo government. Obviously pricing in accordance with «the combined energy market» is music in the ears of European utilities.

However, Hveding strongly emphasised that pricing concepts and formulas used 10 years ago are irrelevant as the place of gas in the energy market was then less well defined. Today gas prices should be «more in line with crude oil-prices,» he said, emphasising he did not mean price parity with crude oil.

Price is not the only aspect about the Soviet — West Europe deal that worries the Norwegians. Comparing the volumes of gas involved in the deal with the latest estimates of demand in the European market undoubtedly leaves the question of what volumes of supply will be available in the market for additional high cost gas from Norway. Massive reserves of gas have recently been established offshore Norway. Part of these reserves can easily await development, while other parts, and particularly associated gas, will have to be developed in the 1990s, not least to maintain an acceptable level of oil production. The Norwegians obviously maintain that a desirable distribution of the sources for gas in continental Europe will be important, and therefore gas from Norway will be required. The crucial question, however, is: how much at the high price required?

The agreement was signed on November 20, and Ruhrgas will receive up to 10.5 billion cubic metres of gas per year at the Czechoslovakian/German border. Deliveries are scheduled to commence in 1984, and will run for 25 years. The build up period will be several years. The deal is part of the proposed scheme to export up to 40 billion cubic metres annually from the Urengoy and Yamburg fields in West Siberia to West Germany, Austria, the Netherlands, Belgium, France, Switzerland and Italy. Detailed price talks have started with other European utilities. ■